EOR In The UK North Sea - Some Economic Considerations

Danny Hann & Alan McGillivray

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D HANN

A McGILLIVRAY

Dr Hann is Shell Research Fellow in the Surrey Energy Economics Centre, University of Surrey.

Alan McGillivray is Senior Lecturer in Economics, Department of Accountancy and Economics, Dundee College of Technology.

1. INTRODUCTION

As oil production in the UK reaches its peak, attention has focused, over the last two or three years, on the need to promote Enhanced Oil Recovery (EOR) in the North Sea in order to maximize production over time. Due to problems of encouraging wasteful capital expenditure, (i.e. gold-plating), the 1981 Budget limited the capital uplift in Petroleum Revenue Tax (PRT) to the period up to PRT payback (when cumulative incomings exceed cumulative outgoings). This meant that any investment occurring after payback would not receive the same relief as capital costs incurred early in the project's life. As a result, calls (UKOOA, 1985) have been made to restore the pre-1981 tax position - at least so the expenditure is uplifted but not necessarily safeguarded, or to introduce some new concession into the offshore tax system. Calls for tax concessions have tended to concentrate on the need to encourage EOR but the tax relief would apply to all incremental investment. As far as oilfield economics are concerned EOR is one set of tools among several which may be used in oilfield management. The chief distinguishing features of EOR methods, however, are that the processes remain untried and unproven in the offshore conditions of the North Sea, and several technical barriers still need to be overcome; whereas most other aspects of incremental investment are already proven and involve less research and development effort, and less risk.

The quantity of oil recovered from reservoirs on the UK Continental Shelf may be significantly increased by the appropriate selection and application of various oil recovery techniques. Enhanced Oil Recovery specifically refers to those techniques used to displace oil from reservoir rock by means other than conventional water or gas injection

(Grist et al, 1984). Such techniques are not necessarily new and have been successfully applied, chiefly in the United States. However, their usage in the extreme and varied conditions of the UKCS will be critically dependent on several economic, technological and oil policy considerations. If oil producers are to engage in EOR in the North Sea then several technological barriers need to be overcome. Moreover, the economics of EOR must take account of the need for adequate rewards for the considerable risks taken by the producing companies.

This paper examines some of the economic issues surrounding EOR in the North Sea. First, we look at the various methods of EOR and try to distinguish EOR from other methods of oil recovery. The problem of defining EOR - obviously crucial when introducing tax concessions - is encountered here and returned to later in the final sections of the paper. Second, the most appropriate EOR techniques for the UKCS are outlined and their general technical problems are highlighted. Finally, using hypothetical field data we examine the economics of incremental investments in the North Sea and the impact of government taxation policy on efforts to increase recovery ratios. The main conclusions of the paper are that serious practical problems associated with the definition and delineation of EOR exist and that further changes to the already highly complex and unstable tax system do not combat the source of tax inefficiency in the UK North Sea.

2. METHODS OF OIL RECOVERY

The processes of oil production have traditionally been categorised into primary, secondary and tertiary stages according to the method of driving or sweeping oil from the rock reservoir. Primary recovery involves the use of gravity and natural pressure in the reservoir to drive the oil from the rock to the production well. Water and/or gas is used to maintain reservoir pressure. Secondary recovery involves the injection of water or gas into the reservoir to maintain pressure or to displace oil in the reservoir. In tertiary stages, gases, chemicals, steam and in situ reservoir combustion may be used to release or drive the remaining oil from the reservoir. In recent times, the distinction between tertiary and prior stages of oil recovery has become confused and less clear. In many cases, techniques of enhanced recovery are applied during primary and secondary recovery stages. Thus the term 'enhanced oil recovery' may be used to replace the term 'tertiary' recovery and 'conventional' recovery replaces both primary and secondary recovery. The differences between EOR and conventional recovery are technological. However, the economic evaluation of EOR is made extremely difficult as it is increasingly problematic to distinguish between those costs and production attributable to EOR, and those attributable to conventional recovery. It is perhaps more appropriate to think in terms of a general process of reservoir management for which a range of techniques may be available, and are employed, at different times during the life of an oilfield, either singly or in combination - and if this is done the case for separate tax status for EOR projects is less obvious.

The application of EOR in the North Sea is fraught with much greater difficulties than those experienced in onshore reservoirs, for instance, in the United States. These difficulties arise mainly from problems with supplying gases and chemicals to offshore locations; to the costs of chemicals for injection into reservoirs; to greater well depths, pressures and temperatures; to the much wider well spacings; and to the costs and problems in acquiring appropriate and reliable information about the performance and efficiency of the recovery methods in the field. This high cost and high degree of uncertainty means that substantial investment is required most importantly in research and development: in reducing the per barrel costs of EOR, in gathering detailed information on the geological characteristics of each reservoir, and in conducting pilot studies of the performance of the most likely technologies for each reservoir. The high cost of such investments in research and information gathering as well as the high levels of risk, may require, it is argued, government assistance towards meeting some of these costs, or some financial incentive to engage in the process. With a weak oil price the trend in the US has been away from basic EOR research toward solving specific problems. This change of emphasis is likely to have serious long run implications for EOR.

In the United States, although EOR techniques have contributed less than 6 per cent to oil production up to 1984, it is estimated that existing and future EOR projects could add 40 per cent to current recoverable US reserves, giving an incremental oil production from EOR of between 14.5 and 34 billion barrels (Brown, 1985). However, with an oil price of around $20 this could fall to well under 10b barrels (Oil and Gas, 1986). Estimates by Shell (Bath et al, 1983) for their main fields in the UKCS indicate an EOR potential of between 9 and 14 per cent of original oil in place. If this range is applied across all UKCS fields then with a current estimate of 2000 million tonnes of proven plus probable reserves (D.En., 1985), the EOR target for the whole of the UK sector of the North Sea could lie between 450m and 700m tonnes. Given estimates of efficiency of EOR processes of between 50 and 70 per cent of target oil, the increase in oil production from the use of EOR processes could amount to between 225m and 490m tonnes. At a price of $17.5 per barrel and a sterling exchange rate of £1 = $1.35 this gives an undiscounted total value of oil production from EOR in the UK North Sea of between £22b and £47b. Other estimates (Hawes, 1985) suggest that between 3% and 7% of oil-in-place from the first generation of fields is the realistic potential for EOR in the UKCS.

Over time, the cost of oil produced by EOR methods may be expected to diminish, hence it is likely that EOR will compete with, and possibly crowd-out, new oilfield investment. The overall average cost per barrel of oil produced from fields coming onstream in the UK North Sea before 1980 was $8 at 1984 prices and exchange rates; for fields now under development average costs are expected to be $17 per barrel, (D.En., 1985). This trend reflects the fact that more recent fields, and prospective development projects are increasingly expensive. With cost-reducing technological changes in EOR methods resulting in increased recovery rates as experience is gained, the cost per barrel of EOR oil may be expected to show an opposite or downward trend in comparison with oil from new discoveries. Thus at some time in the future investment in EOR may be regarded by operators as an alternative to investment in exploration; the number of new fields developed would be reduced as compared to the situation with no EOR.

3. EOR TECHNIQUES IN THE NORTH SEA

As stated, in conventional recovery techniques, oil production from North Sea reservoirs is achieved by the reduction of natural reservoir pressure which causes oil to flow from the reservoir rock within which it is held. The oil then may be swept or driven towards the production well by injected water or gas. Some oil will remain trapped in rock pores by capillary forces. Moreover, because of differential rock porosity in the reservoir, the gas or water drive may by-pass some of the oil causing early breakthrough or fingering. In some cases, the water:oil or gas:oil ratio at the production well may become so high that early shutdown of the well will result. EOR may increase oil production in two ways; by increasing the efficiency of the waterdrive process during secondary production stages, and by reducing the viscosity or the surface tension of the oil remaining after the initial waterflooding process, thereby overcoming the capillary forces and allowing the remaining or residual oil to be driven out of the rock to the production well.

The main EOR techniques with potential application to North Sea reservoirs are various forms of miscible gas injection (chiefly hydrocarbon gas, carbon dioxide and nitrogen), various methods of chemical injection and thermal processes. There are other 'exotic' techniques which are classified as EOR such as mining and microbial EOR but these are, as yet, of much more limited potential with respect to the UKCS.

3.1 Miscible Gas Injection

Miscible hydrocarbon gas injection has already been tested on the Statfjord reservoir in the North Sea (Bath et al, 1983). It operates by dissolving the injected gas into the residual oil. The oil becomes more easily displaced from the rock, and may then be swept to the production well by continuous gas pressure or by further waterdrive. The economics of this process are determined by the availability of supplies of hydrocarbon gas, mainly gas produced jointly with oil or from a nearby gas field. Much of the gas produced from the North Sea reservoirs is, however, committed for sale to the British Gas Corporation, therefore recovery using this method is more likely in those existing fields with large supplies of gas nearby or in new fields where there is no designated market for the gas. The quantity of hydrocarbon gas required is of the order of 1 barrel of liquid petroleum gas (LPG) to every 1.5 to 2.0 barrels of oil recovered.

Inert carbon dioxide or nitrogen gas can provide alternatives to hydrocarbon gas. Carbon dioxide may be injected under pressure into reservoirs in order to reduce the viscosity of the residual oil. In the North Sea reservoirs, conditions are generally favourable for gravity drive. Thus although in some cases carbon dioxide may not be fully miscible with the residual oil (high reservoir pressure is required for miscibility - but not as high as for nitrogen miscibility), recovery rates for immiscible injection are similar to those for miscible injection. In the United States, the recovery efficiency of carbon dioxide injection is expected to be in the region of 1 barrel of oil for 8.0 to 8.6 Mcf of carbon dioxide injected (National Petroleum Council, 1984). In the North Sea, recovery efficiency is likely to be one barrel per 15 Mcf given greater reservoir depths and pressures. Difficulties in the use of carbon dioxide arise from its corrosive nature which tends to exacerbate existing costs of corrosion on production rigs in the North Sea. There are generally severe economic difficulties in supplying carbon dioxide to well heads in the North Sea. With current sources of supply/collection located onshore (from stack gases of coal-fired power stations), carbon dioxide could be piped under pressure to existing rigs. Estimates for the United States indicate an onshore cost of $20 per barrel for this technique (Grist et al, 1984). Furthermore, and crucially, the quantities of carbon dioxide required for large North Sea fields (600 mcfd) far exceeds the quantities currently commercially available onshore, (25 mcfd). Additional production and collection capacity would be required onshore. Estimates of additional investment for production and transport to the North Sea are of the order of £1b (Oilman, 1985). However, a recent find of a gas pocket containing 25-30 per cent carbon dioxide has been made in the North Brae area. This find could improve the feasability of miscible gas injection in North Sea fields by reducing the front-end costs of production, collection and transport of the injection gases. The quantity of gas available could be sufficient for the production of about 4 million barrels of EOR oil. This may increase if the gas were mixed with hydrocarbon gas from fields yet to be developed.

Nitrogen acts in a similar way to carbon dioxide in the recovery of oil but has several distinct advantages in the context of the North Sea. It does not have the same corrosive properties; it creates fewer problems of fingering or gravity tonguing; and although higher pressures are required to achieve miscibility, in fields where gravity drive is stable, then immiscible drive will achieve similar results. Also, carbon dioxide from onshore sources is around twice as expensive to produce as nitrogen, and about 1.7 times as much carbon dioxide per barrel is required as compared to nitrogen. Between 50 and 800 mcf of nitrogen per day would be required, depending on the size of oilfield.

Nitrogen may be produced, by cryogenic processes, from the atmosphere and investment costs of £1b could produce sufficient nitrogen for a number of North Sea reservoirs. Nevertheless, considerable problems remain concerning transportation and the costs of separation plants.

3.2 Chemical Injection

(a) Polymers

The addition of organic polymers, mainly polysaccharides and polyacrylamides, is aimed at achieving an increase in the viscosity of the waterdrive process and at reducing the porosity of rock by sealing off potential avenues for fingering and early breakthrough. Both of these strategies (polymer flooding and polymer plugging) will act to increase the efficiency of any water sweep process and the method may be used in isolation or in conjunction with other forms of gas or chemical injection. The use of polymers will reduce producing water:oil ratios, hence reducing operating costs. The main technical problems with the use of this process in the North Sea are, degradation or shearing of the polymer in the reservoir reducing process efficiency; wide well spacings, typical densities being between 100 and 400 acres per well; reservoir temperature and salinity. The low well densities increase the distance and reservoir pore volume between the injection well and the production well, leading to higher degrees of variation of within reservoir conditions, greater difficulty in controlling the flow paths of any drive process, increased time lag between injection and recovery of oil, increased degradation of the polymer through shearing and biological attack, and increased difficulty and costs in obtaining reliable information regarding the physical and geological characteristics of the reservoir. This information is a prerequisite for the selection and composition of the most appropriate recipe for the polymer slug for each particular reservoir.

Experience in the United States indicates that a quantity of about 40 per cent of reservoir pore volume is injected, with concentrations of polymers varying from an initial 2000 ppm to 100 ppm at the end of the injection. At an average concentration of 1000 ppm, 3 lb of polymer are required per barrel of oil produced. Polymers used in these onshore experiments cost approximately $2.0 per lb at 1975 prices. The costs of polymers for North Sea use may be expected to be significantly higher given the potentially more hostile environment in which the polymers will operate and the higher performance specification required. However, in several North Sea fields where the reservoir fluids have already high mobility, there may be little to be gained from the additional use of expensive polymers.

(b) Surfactants

In the United States, the use of chemical surfactants is thought to have good future potential for enhanced recovery of low to medium viscosity oils. These include the majority of oils in the North Sea. The surfactant process involves the addition of surface active chemicals to water to form a surfactant slug to be injected into the reservoir. The slug reduces the capillary forces that trap the oil in the rock pores and an oil and water bank should be formed ahead of the surfactant slug. Normally a lower cost polymer slug is injected behind the surfactant to preserve the integrity of the high cost surfactant slug, and to improve the sweep efficiency when the surfactant and polymer slugs are driven towards the production well by waterdrive. The reservoir may also be subjected to a pre-surfactant flush to reduce the salinity of fluids within the reservoir, and reduce the incidence of deterioration of the following surfactant by microbial action.

The economics of this process are determined mainly by the cost and efficiency of the surfactant chemicals, which in turn are determined by specific reservoir conditions. The performance of the surfactant is liable to deteriorate as a result of microbial action, mechanical degradation, salinity of reservoir liquids, high temperature and absorption on the rock surface in the reservoir. Surfactants currently available are unsuitable for the North Sea where reservoir temperatures of over 200°F and total dissolved solids of 100,000 ppm are common. It is estimated that surfactants for North Sea reservoirs will cost in the region of £1,000-£2,000 per tonne. At present, process efficiency is estimated at 200 barrels of oil per tonne of surfactant. Although front-end costs are not expected to be high in this process, with injection and materials costs forming 80% of total costs, space constraints of bulk storage on injection platforms will need to be overcome. In addition, considerable research and development expenditures will be required to develop suitable chemical constituents, and to determine the appropriate recipe for each reservoir. This research and development expenditure will involve high risk, given the uncertainties of process performance, future oil prices, and quantities of oil remaining after conventional recovery. In some fields uncertainty may be reduced by pilot study designed to test particular surfactant recipes. Such pilot schemes would cost in the region of £10 million. In other fields, because of the reservoir configuration, pilot studies would not be appropriate. Here the decision to implement a particular EOR technique would be dependent on the availability of detailed information in computer simulation of fluid movements through the reservoir. Much development of information gathering techniques and reservoir simulation methods remain to be done before uncertainties can be reduced to acceptable levels.

3.3 Thermal Processes

These are the dominant form of EOR in the US (accounting for 80% of US EOR) and would traditionally have been classified as tertiary recovery. Steam drive (often used in conjunction with a steam soak) involves injecting steam into a heavy oil reservoir, heating the oil hence enabling it to be displaced by some other method. Because the steam must be injected at pressure so as to retain its heat, it cannot be used at reservoir depths greater than 3,500 feet. In situ combustion involves oil in the reservoir being combusted by downhole heating and sustained by the injection of air or oxygen. This technique may be used in deeper reservoirs than is possible with steam flooding but problems are associated with safety and control and also the production of corrosives damaging the well. Because of these difficulties thermal processes are less likely candidates for major use in UKCS fields.

4. THE ECONOMICS OF INCREMENTAL INVESTMENT PROJECTS

An EOR project is one form of incremental investment: a change to the original oilfield programme is planned at some period into the oilfield's life. Hence in order to provide an initial framework for the examination of some economic issues associated with this type of investment on the UKCS we refer to incremental investment generally with only specific reference to EOR where relevant. To facilitate this analysis we have developed hypothetical projects undertaken at various points in time for varying lengths of time; the details are presented in Table 1. By showing profitability measures under a selection of scenarios for the key economic variables we are able to discuss government policy responses.

In conjunction with the oilfield data outlined in Table 1, we employ three different oil paths. The Constant Real Price (CRP) scenario assumes an oil price of $17.50 in 1986 which then stays constant in real terms. The Limited Price Decline (LPD) scenario assumes a $10 oil price in 1986, henceforth increasing in line with inflation. The Use of Monopoly Power (UMP) oil price assumes a barrel of Brent crude costs $25 in 1986 and then involves a continuing three yearly cycle comprising a real 15% increase followed by a 2% real decline in each of the other two years. Our central sterling/dollar exchange rate is assumed to average £1 = $1.40 in 1986 and onwards; the weak pound scenario is £1 = $1.20 and the strong pound is £1 = $1.60. Central cost inflation is assumed to be 5% p.a.; whilst slow cost inflation is 3% and rapid inflation is 7%. The fiscal environment remains as in 1985.

Table 2 shows that only with our high oil price is the extension to Field A viable. Moreover, Table 2 illustrates the importance of the discount rate in assessing oilfield investment projects. Under the UMP scenario a positive real NPV with a 10% discount rate is altered to a negative amount by a 20% discount rate. Thus, if companies mistakenly account for risk by raising their discount rate, this will obviously have a severe impact on incremental projects. However, if other methods of allowing for risk are employed, such as requiring a certain positive level of NPV to be reached or by some decreasing risk factor on production revenue, then post-tax real NPVs will be reduced in all cases.

In Table 3, it is apparent that the extensions to Fields B and C are only likely to be undertaken with a high oil price. Field D extension has a positive NPV even with an oil price of $10 in 1986. Although the imposition of the tax system does reduce the NPVs of Field D extension the effect is not as dramatic as for Field B. With a high oil price, strong pound and slow cost inflation a health pre-tax NPV of £138 million is changed to a single figure NPV post-tax.

Table 3 shows that the tax system can have a considerable and harmful impact on the profitability of the oilfield extensions. For the tax system to operate in a non-distortionary or neutral manner decisions as to production profiles and investment plans which would have been made pre-tax should also be made post-tax. If only supernormal or pure profit is taxed then the economic decision-making process is unaffected by the tax. Much attention has focused on the disincentive impact of the tax system on incremental investment generally and EOR in particular and suggestions of new tax concessions have been proposed and analysed (UKOOA, 1985; Kemp and Rose, 1984). The introduction of further sets of concessions into the tax system is the pragmatic response to the problem of incremental investment. These proposals, such as UKOOA's Incremental Investment Allowance, would be introduced into an already familiar system and would ensure small projects on small fields would benefit from existing PRT concessions. However, focusing on the need for tax concessions misses the essential point that the disincentive and distortionary effects of the tax system are indicative of deficiencies in the tax system which cannot be remedied by ad hoc changes.

Moreover there are practical problems associated with the introduction of tax concessions. First, whilst it may be desirable to make the Field B extension more attractive post-tax, it may not be desirable to make an already attractive project yet more profitable. Therefore concessions need to be able to distinguish between projects which require tax concessions and those which are relatively profitable under the existing régime. Second, as it is, an incremental investment project started in 1986 and involving high levels of capital expenditure would result in a reduction in short term tax revenues even though the total tax take would increase. Concessions based on, say, uplifting all capital costs would further reduce short-term tax revenues. Hence the increased, but later, tax revenues would be passed on to a subsequent government, possibly of a different political party. This is a situation unlikely to be welcomed by the Chancellor of the Exchequer or by the government in power. Political uncertainty is thus introduced as to the timing and character of the concessions. In addition there is the likelihood of further changes occurring due to changing oil market economics or changing circumstances unrelated to UK oil but which, for instance, necessitate the raising of government revenue; this seems particularly important given the volatile nature of the international oil market.

Third, tax concessions must apply to only the costs and revenues associated with the incremental project. This is an extremely difficult problem to overcome - particularly with respect to EOR projects - as it is often almost impossible to distinguish between production attributable to the incremental project and the existing oilfield's production. Similarly there are likely to be considerable difficulties separating the capital expenditure of the incremental project from that of the existing field. Some formula would need to be developed which would not be susceptable to uncertain discretionary change by the government and yet would be flexible enough to deal with characteristics of individual oilfields; complex legislation would be required. Tax concessions would unavoidably tend to be arbitrary as to how much oil and how much expenditure are directly attributable to the incremental project.

A related point is that much of the pressure for tax concessions is justified on the basis of the special characteristics of EOR projects. It tends to be argued that EOR is a special type of incremental investment due to the research and development expenditure associated with EOR and the reservoir-specific nature of EOR technology. In terms of economic theory it is difficult to view EOR as different from any other incremental investment project but it has proved useful as a bargaining tactic focusing attention on oil company attempts to maximize oil extraction on the UKCS. As explained above, the differences between EOR, primary, secondary and tertiary recovery schemes are technological and are becoming increasingly blurred. Due to changed economic expectations, changed technology or improved reservoir knowledge since the initial work programme, the oilfield programme is amended. The introduction of the concessions to assist in the high levels of research and development expenditure would face the problem of allocating this expenditure to a single oilfield project. At present, any exploration and appraisal expenditure on the UKCS may be offset against PRT payments. However, with respect to research and development expenditure it may be extremely difficult to identify costs attributable to the North Sea, let alone to a specific field.

If the EOR project is granted separate field status so as to surmount these tax concession problems, then there appears to be no reason preventing a continuing fragmentation of UKCS oilfields into smaller and smaller units. The principle of the oilfield being the taxable unit would be lost. Moreover, on grounds of progressivity it is desirable that the EOR project (or indeed, any incremental investment project which increases oilfield profitability) should be taxed at a higher rate than profit from the existing field. Ideally the average rate of tax should be increasing and the marginal rate decreasing; the existing system often behaves regressively (Rowland and Hann, forthcoming).

5. CONCLUSION

It is apparent that there are at least two serious problems associated with tax relief for incremental investment projects of all types. First, in practise, there is the problem of being unable to allocate costs and production precisely to the incremental project. For instance, the EOR technique of surfactant flooding results in a largely indeterminate increase in oilfield production perhaps several months later. Second, in principle, it is mistaken to concentrate on the introduction of a further set of tax concessions into an already complex and unstable system when it is the shortcomings of the tax system itself which are the root cause of tax disincentives to conventional incremental investment and to EOR. The wholesale changing of the tax system and the introduction of some sort of resource rent tax would pre-empt any need for concessions to encourage incremental investment. Furthermore, a rent tax, with the tax base being pure profits hence leaving the resource allocation decision unaffected by the tax (Clunies Ross, 1982), would be relatively stable and would tend to reduce uncertainty. Uncertainty arises from whether or not tax concessions are to be introduced, when they are likely to be introduced, what form they are likely to take, and then, if they will remain in force. A resource rent tax would be able to deal with other problems such as the normal return on capital, taxing risk and regressivity more effectively than the existing system (Rowland and Hann, forthcoming).

Political and bureaucratic considerations also influence tax concessions, particularly with their timing. The interests of political factions and departmental rivalries often act to influence the nature of the concessions (Hann, 1985). Pressure for tax concessions from industry lobby organizations implicity show the industry's satisfaction with the existing system, reflecting familiarity and accummulated expertise. Again this tends to distort the oil tax process, adding to uncertainty.

There is little doubt that the existing tax system discourages incremental investment, hence, some tax changes (e.g. the UKOOA proposals) are desirable. This is a pragmatic argument which should be dealt with in the very near future if incremental investment projects are to have any sort of impact on recovery from the first generation of UK offshore oilfields. A delay could result in an opportunity being missed. However, whilst the issue at present is concerned mainly with conventional incremental investment projects, in the future it is likely to be for EOR as a special type of incremental investment again needing special tax treatment: thus the process will recurr. The issue of tax concessions for conventional incremental investment and for EOR in the North Sea highlights the deficiencies of the existing tax system. If the source of the problem - rather than its symptoms - is addressed, then a complete overhaul of the tax system is required.

TABLE 1

PROJECT DATA

	Initial field size - recoverable reserves (mm. bbls.)	Production (mm. bbls.)	Extension: Operating costs £ per bbl. (money of the day)	Extension: Capital costs £ per bbl. (money of the day)
Field A	2000	93	4.1	4.7
Field B	415	45	8.7	6.6
Field C	150	30	9.4	10.3
Field D	100	7	15.1	3.7

TABLE 2

POST-TAX REAL NPV OF EXTENSION ON FIELD A

(mm 1985 sterling)

Economic Conditions	10% d.r.	20% d.r.
CRP Central exchange rate Central cost inflation	-16	-52
UMP High exchange rate Rapid cost inflation	19	-35
UMP High exchange rate Slow cost inflation	63	-11
LPD Low exchange rate Slow cost inflation	-31	-58

TABLE 3

REAL NPV (MM. 1985 STERLING) OF EXTENSIONS ON:

Economic Conditions	Field B	Field C	Field D
Post-Tax			
CRP Central exchange rate Central cost inflation	-31	-51	13
LPD Low exchange rate Slow cost inflation	-47	-78	11
UMP High exchange rate Slow cost inflation	9	24	33
Pre-Tax			
CRP Central exchange rate Central cost inflation	-88	-54	19
LPD Low exchange rate Slow cost inflation	-172	-87	12
UMP High exchange rate Slow cost inflation	138	100	49

10% discount rate

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